Types of corrosion in Oil and Gas Industry

Sweet corrosion (CO_2 corrosion)
CO_2 corrosion has been a recognized problem in oil and gas production and transportation facilities for many years. CO_2 is one of the main corroding agents in the oil and gas production systems. Dry CO_2 gas is not itself corrosive at the temperatures encountered within oil and gas production systems but is so when dissolved in an aqueous phase through which it can promote an electrochemical reaction between steel and the contacting aqueous phase. CO_2 will mix with the water, forming carbonic acid making the fluid acidic. CO_2 corrosion is influenced by temperature, increase in pH value, composition of the aqueous stream, presence of non-aqueous phases, flow condition, and metal characteristics and is by far the most prevalent form of attack encountered in oil and gas production. At elevated temperatures, iron carbide scale is formed on the oil and gas pipe as a protective scale, and the metal starts to corrode under these conditions. CO_2 corrosion can appear in two principal forms: pitting (localized attack that results in rapid penetration and removal of metal at a small discrete area) and mesa attack (a form of localized CO_2 corrosion under medium-flow conditions). Various mechanisms have been postulated for the CO_2 corrosion process but all involve either carbonic acid or the bicarbonate ion formed on dissolution of CO_2 in water.

Sour corrosion (H_2S corrosion)
The deterioration of metal due to contact with hydrogen sulfide (H_2S) and moisture is called sour corrosion which is the most damaging to drill pipe. Although H2S is not corrosive by itself, it becomes a severely corrosive agent in the presence of water leading to pipeline embrittlement. Hydrogen sulfide when dissolved in water is a weak acid, and therefore, it is a source of hydrogen ions and is corrosive. The corrosion products are iron sulfides (FeSx) and hydrogen. Iron sulfide forms a scale that at low temperature can act as a barrier to slow corrosion. The forms of sour corrosion are uniform, pitting, and stepwise cracking

Sour corrosion (H_2S corrosion)
The deterioration of metal due to contact with hydrogen sulfide (H_2S) and moisture is called sour corrosion which is the most damaging to drill pipe. Although H_2S is not corrosive by itself, it becomes a severely corrosive agent in the presence of water, leading to pipeline embrittlement. Hydrogen sulfide when dissolved in water is a weak acid, and therefore, it is a source of hydrogen ions and is corrosive. The corrosion products are iron sulfides (FeS) and hydrogen. Iron sulfide forms a scale that at low temperature can act as a barrier to slow corrosion. The forms of sour corrosion are uniform, pitting, and stepwise cracking.

Crevice corrosion
Crevice corrosion is normally a localized corrosion taking place in the narrow clearances or crevices in the metal and the fluid getting stagnant in the gap. This is caused by concentration differences of corrodents over a metal surface. Electrochemical potential differences result in selective crevice or pitting corrosion attack. Oxygen dissolved in drilling fluid promotes crevice and pitting attack of metal in the shielded areas of drill string and is the common cause of washouts and destruction under rubber pipe protectors.

Erosion corrosion
The erosion corrosion mechanism increases corrosion reaction rate by continuously removing the passive layer of corrosion products from the wall of the pipe. The passive layer is a thin film of corrosion product

that actually serves to stabilize the corrosion reaction and slow it down. As a result of the turbulence and high shear stress in the line, this passive layer can be removed causing the corrosion rate to increase. The erosion corrosion is always experienced where there is high turbulence flow regime with significantly higher rate of corrosion and is dependent on fluid flow rate and the density and morphology of solids present in the fluid. High velocities and presence of abrasive suspended material and the corrodents in drilling and produced fluids contribute to this destructive process. This form of corrosion is often overlooked or recognized as being caused by wear.

Microbiologically induced corrosion

This type of corrosion is caused by bacterial activities.

The bacteria produce waste products like CO_2, H_2S, and organic acids that corrode the pipes by increasing the toxicity of the flowing fluid in the pipeline. The microbes tend to form colonies in a hospitable environment and allow enhanced corrosion under the colony. The formation of these colonies is promoted by neutral water especially when stagnant. Numerous reports of the presence of microbes in reservoirs had been published. It was found that found abundant microbial flora indigenous in oil field formation waters, which included species of Bacillus, Pseudomonas, Micrococcus, Mycobacterium, Clostridium, and Escherichia. Escherichia is reported to contain hydrogenase, an enzyme that utilizes molecular hydrogen and may be associated with cathodic hydrogen depolarization, causing corrosion of steel casings and pipes in the oil field. Bacteria that form slime (some form of polysaccharides), such as Achromobacter sp., Flavobacterium sp., and Desulfuricans sp., will adhere to each other, forming a large mass. They also adhere to the walls of the pores, causing severe plugging problems at injection wells. Microbiologically induced corrosion (MIC) is recognized by the appearance of a black slimy waste material or nodules on the pipe surface as well as pitting of the pipe wall underneath these deposits.

Stress corrosion cracking

Stress corrosion cracking (SCC) is a form of localized corrosion which produces cracks in metals by simultaneous action of a corrodent and tensile stress. It propagates over a range of velocities from 10−3 to 10 mm/h depending upon the combination of alloy and environment involved. SCC is the cracking induced from the combined influence of tensile stress and a corrosive medium. The impact of SCC on a material seems to fall between dry cracking and the fatigue threshold of that material. SCC in pipeline is a type of environmentally associated cracking. This is because the crack is caused by various factors combined with the environment surrounding the pipe. The most obvious identifying characteristic of SCC in a pipeline is high pH of the surrounding environment, appearance of patches, or colonies of parallel cracks on the external of the pipe.

Corrosion mitigation in the oil and gas industry

Oil field corrosion challenges are not static phenomena.

Fluid characteristics change over time, resulting in systems becoming less responsive to established corrosion mitigation programs. Within the sphere of corrosion control and prevention in the oil and gas industry, there are technical options such as cathodic and anodic protection, material selection, chemical dosing, and the application of internal and external coatings. It is widely recognized within the oil and gas industry that effective management of corrosion will contribute towards the maintenance of asset integrity and achieve optimization of mitigation, monitoring, and inspection costs.

Recommended materials in the oil and gas industry

Carbon steels	Bulk fluids, crude pipelines, flow lines, water and steam injection lines, production and test separators, KO drums, storage tanks
Low- and medium-alloy steels	Well head items, chokes, manifolds and well components with sour and high-temperature applications
Straight chromium steels (chromium 12% to 18%)	Christmas trees, well heads, downhole rods, valves and casing pipes
Chromium-nickel steels (chromium >18%, nickel >8%)	Valve trims, instruments and materials of separators and tanks low-chloride levels
Nickel steels (2.5%, 3.5%, 9% nickel)	Rarely used in oil and gas sectors, LNG storage tanks, piping and Pumps
Duplex stainless steels (22% chromium duplex, 25% chromium super, duplex)	Piping, vessel and tank internals where a very high level of chlorides is present
Nickel-chrome (inconels) Ni-Cr-Fe alloys	Well head and flow lines, manifolds wit high sour and temperature applications

Corrosion monitoring is the practice of measuring the corrosivity of process stream conditions by the use of probes (mechanical, electrical, or electrochemical devices) which are inserted into the process stream and continuously exposed to the process stream condition. Corrosion monitoring techniques alone provide direct and online measurement of metal loss/corrosion rate in oil and process systems. One of the methods is to carry out the on-stream inspection by doing the wall thickness measurements periodically on fixed and vulnerable locations on the equipment, piping, and pipelines to assess the material conditions and corrosion rates. Also, corrosion is monitored by placing electronic probes in the pipelines and by measuring the change in the electric resistance in the probe coil. The cross-country pipelines are normally checked with intelligent pigging operations like magnetic flux or ultrasonic pigs. These pigs will detect the internal conditions of the pipeline and corrosion conditions on the pipe wall thickness and also indicate the wall thickness available on the pipe wall.

Most of the equipment like separators, drums, and heaters are checked for corrosion during annual shutdown and turnaround operations. Based on the physical assessment of the material conditions, corrective action is initiated to change the material or replace the equipment or at times do temporary repair work before replacementis carried out. In practice, it is observed that physical inspection is the best method of monitoring corrosion and assessing the material conditions. Other areas where corrosion monitoring and inspection are necessary in the oil and gas industry include drilling mud systems, digesters, water wash systems, flow lines, transport pipelines, desalters, sour water strippers and crude overheads.

Pitting corrosion

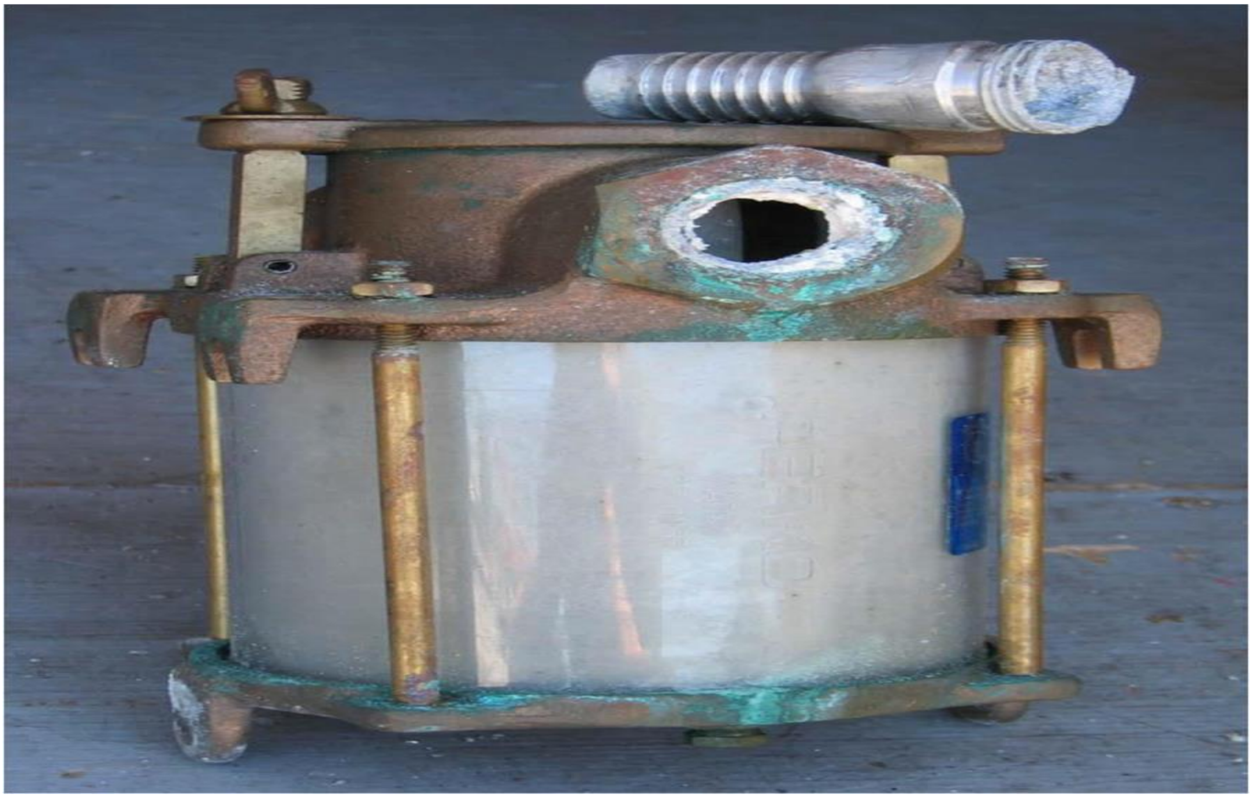
Oxygen corrosion

Oxygen corrosion

Crevice corrosion

MIC

Stress Cracking Corrosion



Galvanic Corrosion